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BE-CEC-192

November 2, 2004

Steve, Munro, Compliance Project Manager
Compliance Project Manager
California Energy Commission
1516 9th Street, MS 2000
Sacramento, CA 95814-5512

Subject: Blythe Energy Project
PETITION FOR AIR QUALITY CONDITIONS MODIFICATIONS

Dear Mr. Munro:

Enclosed for your review, please find our revised "Petition for Air Quality Conditions Modifications" with attachments for the Blythe Energy Project. This petition has been revised to reflect discussions with Gabriel Taylor regarding the proposed CO emission levels and startup definition.

If you have any questions regarding this petition, please contact me at (760) 922-9950 ext. 227.

Very truly yours,

Blythe Energy, LLC
A Delaware Limited Liability Company

By: Chris Allen

Christopher L. Allen
General Manager

cc: A. DeSalvio, MDAQMD
R. Piper, FPL Energy
C. Mosley, Blythe Energy
S. Head, ENSR

PETITION FOR
AIR QUALITY CONDITIONS MODIFICATIONS

Submitted By:

BLYTHE ENERGY, LLC
BLYTHE, CALIFORNIA

Submitted to:

CALIFORNIA ENERGY COMMISSION

Prepared by:

ENSR INTERNATIONAL

10056-002-001-CEC

November 2004

Blythe Energy Project
Petition for Air Quality Conditions Modifications
99-AFC-08

Submitted to:

California Energy Commission

Submitted by:

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10056-002-001-CEC

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1.0 INTRODUCTION AND PROJECT SUMMARY

The Blythe Energy Project (BEP) is filing this petition for proposed modifications to the California Energy Commission (CEC) Decision for the BEP, Docket 99-AFC-8. This petition incorporates changes to the project's Authority to Construct (ATC) permits B007953 and B007954 for the combustion turbine generators (CTGs). An application for modifications of these ATC permits has been submitted to the Mojave Desert Air Quality Management District (MDAQMD) and a draft permit was issued by MDAQMD in August 2004.

The plant is powered by two F-class Siemens V84.3A CTGs. Exhaust gas from the CTGs is directed to two supplementary fired heat recovery steam generators (HRSGs) for the generation of steam that drives the steam turbine generator (STG). Supplementary firing (duct burner firing) capability is provided in each HRSG to generate additional steam for peak power production. The BEP facility utilizes Selective Catalytic Reduction (SCR) systems for the control of oxides of nitrogen (NO_x) emissions. Fuel for the CTGs and duct burners is exclusively natural gas. A mechanical draft cooling tower equipped with high efficiency drift eliminators provides heat rejection for the steam cycle. A diesel-fired internal combustion engine is used to drive a fire water pump engine.

This petition includes proposed modifications to the associated CEC Conditions of Certification to allow increases to the startup and shutdown emission limits for the CTGs. The proposed modification to CEC Conditions AQ-6, AQ-7 and AQ-8 will allow for these modifications.

Blythe Energy, LLC obtained a variance from the MDAQMD (Case No. 03-009-I-1) and an Administrative Order of Consent (No. R9-2004-01) from the United States Environmental Protection Agency (EPA) that allows operation of the facility at the increased startup emission levels until the ATC and Prevention of Significant Deterioration (PSD) permits are modified.

This petition to amend the Commission Decision approving the project contains all the information that is required pursuant to 20 CCR Section 1769, Post Certification Amendments and Changes, of the California Energy Commission's Siting Regulations.

2.0 DESCRIPTION OF PROPOSED AIR QUALITY CONDITION MODIFICATIONS

Blythe Energy, LLC is requesting several modifications to the Air Quality Conditions of Certification in the Commission's Decision for the BEP. The modifications concern Conditions of Certification AQ-6, AQ-7 and AQ-8. Conditions AQ-6 and AQ-7 specify the maximum daily and annual emission rates, respectively, for particulate matter (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), and carbon monoxide (CO). Condition AQ-8 defines three types of startups and shutdown, the durations of each type of startup and shutdown, and the emission limits during startups and shutdowns. BEP requests that Conditions of Certification AQ-6, AQ-7, and AQ-8 be modified to allow for the proposed increases to the startup and shutdown emission limits for CO. Projected VOC emissions might also increase slightly during startup, however BEP is not requesting a modification in the daily or annual potential to emit (PTE) for VOC.

During the initial permitting of BEP in 1999 - 2000, relatively low startup emission rates for the CTGs were assumed. Historically, power plants have not generally been required to monitor or report emissions data during startup, leaving a dearth of empirical emissions information. Further, little information was known about the performance of Siemens combustion turbines equipped with dry low-NO_x combustors. Only estimated (and not guaranteed) emissions information was available from Siemens at the time of the initial application. Based on the information available, the initial permit application underestimated the level of emissions during startup.

Subsequent to the initial permitting, additional vendor input and data collected during commissioning of BEP, as well as the operation and permitting of other similar facilities to date, it has been determined that the currently permitted BEP CO startup emission rates are not achievable. By reviewing the emission rates being produced at other similar facilities, as well as new, more detailed manufacturer's data, BEP is proposing modified startup emission rates for CO. Emissions of NO_x, SO_2, and PM_{10} are not affected.

Although this application includes what are considered to be more realistic startup emissions estimates, it should be noted that the facility has only limited data and there is still not much publicly-available data on actual emissions during these transient operations.

In a combined-cycle system, bringing a power block online is a complicated process. The power block at BEP consists of two CTGs and one STG and the startup sequence consists of multiple steps in which the equipment is "ramped up" to normal operating conditions. This ramp-up period consists of various gas turbine speed and load conditions. During the ramp-up period, the HRSGs, steam drums, steam turbine, steam piping and emissions control equipment are heated and brought to a stable operating condition. During a typical startup, both machines are often started within 1 to 5 minutes of each other and ramped up to a load where they are held until the HRSGs and steam system reach a specified temperature and pressure. At that point, the STG is started and operated as steam becomes available to drive the system. The time needed to bring the units on-line can vary based on site conditions, time elapsed since last operated, and external factors such as Control Area Operator restrictions for putting electrical power into the grid.

The conditions currently contain CO and NO_x emission and duration limits for cold, warm and hot startups as well as shutdowns. However, the limited operational data available to date at BEP indicates that the emissions during a startup are as much a function of dispatch requirements as they are a function of the time needed to bring the combined cycle system to its operating temperature and pressure. Therefore, BEP is also proposing to streamline the current permit into a single worst-case startup emission and duration limit. It is proposed that the warm start, hot start and cold start emission limits (for NO_x as well as CO) and time limitations be eliminated (Condition of Certification AQ-8). These additional limits are not needed to ensure compliance with any requirements or to ensure that health standards or PSD increments are met. Revision of the daily CO limit to reflect potential increases to the startup emissions, and assuming multiple startups in a single day, is also proposed in lieu of the current duration limits.

A worst case startup CO emission rate was determined, based on review of the available data, and accounting for other factors such as dispatch requirements, hold time under unusual conditions, and ambient temperature. This worst case CO value is 3,600 lb/event per CTG. In addition, a worst case daily limit was determined based on one worst case startup, one warm start, one hot start, three shutdowns and the remaining hours at maximum operating load. This scenario is considered unlikely, but would allow for a problematic day related to equipment issues and/or dispatch variability. This daily worst case CO value is 8,004 lb/day per CTG.

The current facility annual CO estimate of 306 tons per year (tpy) was also reviewed. This potential to emit (PTE) was based on 160 startups and shutdowns and 7,564 hours of peak load operation per year. Instead, a revised annual scenario has been developed based on almost daily startups, which is the operating mode currently employed by BEP. Table 1 below provides a revised annual PTE calculation based on a mix of startups, a maximum hourly limit of 4 ppm, and a scenario with 300 startups and shutdowns per year.

The calculated PTE under the scenario shown in the table is 621 tpy. The annual scenario represented in the table of nearly daily starts is considered a reasonable worst case for BEP, but many other operating approaches may be used. As noted in the table footnote, the assumptions used regarding the number of events and durations are not meant to be used as permit limits. For instance, BEP may run continuously in a base load operating mode, in which case the normal operating hours could be larger (up to 8,760 hours/year). Or there may be more cold and/or warm starts, but then there would most likely be more downtime. Typical actual emissions are also generally expected to be below the emissions levels shown, which would then allow for more events within the projected annual emissions PTE.

Table 1
Annual CO PTE Estimation

Type of Operation	No. of Events	Total Hours	CO (lbs/event)	Total Emissions (lbs)
Cold Start (CT1)	10	36.8	3600	36000
Cold Start Downtime (CT1)		480.0		0
Warm Start (CT1)	50	100.8	2200	110000
Warm Start Downtime (CT1)		400.0		0
Hot Start (CT1)	240	296.0	1200	288000
Hot Start Downtime (CT1)		960.0		0
Shutdown (CT1)	300	150.0	250	75000
Operation (CT1)		6336.3	17.5	110886
Total CT1 Hours		8760.0		0
Cold Start (CT2)	10	31.0	3600	36000
Cold Start Downtime (CT2)		480.0		0
Warm Start (CT2)	50	74.2	2200	110000
Warm Start Downtime (CT2)		400.0		0
Hot Start (CT2)	240	256.0	1200	288000
Hot Start Downtime (CT2)		960.0		0
Shutdown (CT2)	300	150.0	250	75000
Operation (CT2)		6408.8	17.5	112155
Total CT2 Hours		8760.0		
Facility Annual Total (pounds per year)				1241040
Facility Annual Total (tons per year)				**621**
Number and duration of events or emissions for other than worst case startup or maximum operating hour are not intended as permit limits, but rather are assumptions for calculation purposes only. Slight differences in duration of events for the second combustion turbine (CT2) assume that its startup will take less time than the first combustion turbine (CT1).				

This CO emission level is proposed as the revised CO annual PTE. Duct firing will not be employed during either the startup or shutdown sequence. The proposed startup emission limits are summarized in Table 2.

Emissions of VOC vary only slightly during a startup event compared to normal operations based on initial source testing. There are daily and annual emission limits for VOC in Conditions of Certification AQ-6 and AQ-7. VOC emissions could vary slightly from those assumed in the previous application, but permitted daily and annual potential to emit will not be exceeded due to the revision in startup emissions. Therefore, there are no proposed changes to the VOC permitted emission limits in the Conditions of Certification AQ-6 and AQ-7.

Table 2
Proposed BEP Emission Rates for Each CTG/HRSG

Pollutant	Worst Case Startup (lb/event)[a]	Maximum Daily Limit (lb/day)	Maximum Annual PTE (tons/year)
CO	3,600	8,004	310.3[b]

a. Duration for a worst case startup event is about 4 hours

b. Total for two CTG/HRSG is 620.6 tpy. Adding in potential CO emissions from the firewater pump of 0.05 tpy yields a facility-wide PTE of 621 tpy.

3.0 CHANGES TO CONDITIONS

In order to incorporate the modifications discussed in Chapter 2, BEP proposes to modify Conditions of Certification AQ-6, AQ-7, and AQ-8. BEP requests the following changes and additions be made to the air quality Conditions of Certification and Verification in the Commission Decision. ~~Strikethrough~~ indicates deleted text and underlined indicates replacement or new text.

The proposed modifications will not materially alter the conclusions contained in the Commission Decision. Furthermore, the proposed modifications will satisfy all applicable existing Conditions of Certification other than the air quality conditions proposed below, and no other changes in conditions are required.

AQ-6 Emissions from the turbines, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:

a. NOx — 5,762 lb/day, verified by CEMS.

b. CO — ~~3,808~~ 8,004 lb/day, verified by CEMS.

c. VOC as CH4 — 239 lb/day, verified by compliance tests and hours of operation in mode.

d. SOx as SO2 — 130 lb/day, verified by fuel sulfur content and fuel use data.

e. PM10 — 565 lb/day, verified by compliance tests and hours of operation.

Verification: The project owner shall submit the following in each Quarterly Operations Report: All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430; operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip; any maintenance to any air pollutant control system (recorded on an as performed basis); and any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ-7 Emissions from this facility, including the cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx — 202 tons/year, verified by CEMS.

b. CO — ~~306~~ 621 tons/year, verified by CEMS.

c. VOC as CH4 — 24 tons/year, verified by compliance tests and hours of operation in mode.

d. SOx as SO2 — 24 tons/year, verified by fuel sulfur content and fuel use data.

e. PM10 — 103 tons/year, verified by compliance tests and hours of operation.

Verification: The project owner shall submit the following in each Quarterly Operations Report: All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430; operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip; any maintenance to any air pollutant control system (recorded on an as-performed basis); and any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ-8 Emissions of CO and NOx from the turbines shall only exceed the limits contained in AQ-5 during startup and shutdown periods as follows:

a. Startup is defined as the period beginning with ignition and lasting until either the equipment complies with all operating permit limits for two consecutive 15-minute averaging periods or four hours after ignition, whichever occurs first. ~~the equipment has reached operating permit limits. Cold startup is defined as a startup when the CTG has not been in operation during the preceding 48 hours. Hot startup is defined as a startup when the CTG has been in operation during the preceding 8 hours. Warm startup is defined as a startup that is not a hot or cold startup.~~ Shutdown is defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.

~~b. Transient conditions shall not exceed the following durations:~~

~~i. Cold startup — 3.7 hours~~

~~ii. Warm startup — 2.0 hours~~

~~iii. Hot startup — 1.2 hours~~

~~iv. Shutdown — 0.5 hour~~

b~~c~~. During a ~~cold~~ startup or shutdown emissions shall not exceed the following, verified by CEMS:

i. NOx — 376 lb.

ii. CO — ~~403~~ 3600 lb.

~~d. During a warm startup emissions shall not exceed the following, verified by CEMS:~~

~~i. NOx — 278 lb.~~

~~ii. CO — 253 lb.~~

~~e. During a hot startup emissions shall not exceed the following, verified by CEMS:~~

~~i. NOx — 260 lb.~~

~~ii. CO — 172 lb.~~

~~f. During a shutdown emissions shall not exceed the following, verified by CEMS:~~

~~i. NOx — 170 lb.~~

~~ii. CO — 48 lb.~~

Verification: The project owner shall include a detailed record of each startup and shutdown event in the Quarterly Operations Report. Each record shall include, but not be limited to, duration, fuel consumption, total emissions of NOx and CO, and the date and time of the beginning and end of each startup and shutdown event. Additionally, the project owner shall report the total plant operation time (hours), number of startups, hours in ~~cold~~ startup~~, hours in warm startup, hours in hot startup, hours in~~ and shutdown, and average plant operation schedule (hours per day, days per week, weeks per year).

4.0 NECESSITY FOR AIR QUALITY CONDITION MODIFICATIONS

Modifications of the Commission Decision related to CO emissions during startup are requested in this petition. BEP cannot operate the CTGs in compliance with the short-term startup emission limits without the proposed modifications. Modifications of the current lb/event and annual emission limits for CO are also required to accommodate the changes to the startup and shutdown emission rates.

5.0 TIMING OF REQUEST FOR AIR QUALITY CONDITION MODIFICATIONS

As discussed in Chapter 2, only limited information regarding emissions during startup and shutdown of the CTG was available during the BEP certification proceeding. Although some additional information has subsequently become available, the characterization of the emissions during startup and shutdown is still uncertain since there is very little actual operating data at BEP and very few Siemens V84.3A CTGs in operation elsewhere. This lack of data is especially true during ambient conditions that have not been experienced during actual operation of the facility, such as wintertime conditions.

The proposed modifications change some of the assumptions upon which the Final Decision was based. Therefore, revised air quality analyses are provided with this petition. These analyses include an air quality impact analysis (Chapter 6) and a discussion of the laws, ordinances, regulations, and standards (LORS) that could be affected by these changes (Chapter 7). These analyses demonstrate that none of the findings of the Final Decision are adversely affected by the proposed changes. Since the environmental impacts of the project remain insignificant, the proposed modifications should be permitted.

6.0 IMPACT ANALYSIS OF AIR QUALITY CONDITION MODIFICATIONS

The proposed air quality condition modifications will have no significant effect on the technical areas analyzed in the Final Commission Decision as issued in March 2001. Anticipated operations will not change as a result of the change in these conditions. Operation activities for the facility will conform to all practices described in the Final Commission Decision.

Only minor changes in air quality impacts during normal operations are involved. An air quality impact analysis is provided to demonstrate this fact.

6.1 Modeling Procedures

The procedures used for this modeling assessment, including model selection and input options, meet EPA modeling guidelines. Specific information, such as source parameters, building wake effects, receptor grids, and meteorological data was obtained from previous approved modeling of the BEP facility. The digital modeling files were updated to reflect the worst-case CTG emissions for this application. The latest version of the Industrial Source Complex Short-Term (ISCST3 Version 02035) dispersion model was used. The modeling methods follow the requirements in the Guideline on Air Quality Models (EPA, 2003).

The CAAQS for CO are more stringent than the NAAQS. The short-term CO emissions will increase due to higher startup emissions and compliance with the 1-hour and 8-hour CO CAAQS must be demonstrated. Modeling was performed for short-term CO for the worst-case conditions, with updates to the emission rates due to the increase in startup emissions as described in Chapter 2. The proposed fire water pump engine was also included in the model runs to determine the overall facility impacts.

Dispersion modeling was conducted to verify that the proposed CO permit limits do not change any of the conclusions about the impacts in the project vicinity, i.e., that the operational impacts will not cause or contribute to violations of the AAQS during routine operations. This modeling demonstrated that all impacts will be below the CO CAAQS, as discussed further in this Chapter, and hence the modified BEP facility does not cause or contribute to an exceedance of an ambient air quality standard.

6.1.1 Source and Receptor Locations

The locations of the CTG/HRSG exhaust stacks and fire water pump engine were obtained from the previously approved digital modeling files. The receptor grids and terrain elevations were also obtained from the digital modeling files.

6.1.2 Meteorological Data

Consistent with the previous modeling, surface meteorological data collected at a monitoring station located in the City of Blythe monitoring station from 1989 to 1993 were used in this application. Concurrent mixing height data were obtained from the Desert Rock, Nevada upper air station. This dataset is the most readily available meteorological dataset that is representative of the dispersion conditions at the BEP facility.

6.1.3 Stack Parameters and Emissions

Table 3 provides the stack parameters for the BEP CTGs for the worst-case conditions for both the one and eight hour period. The original application provided emission rates and stack parameters for many different cases representing different load, ambient temperature, and equipment configurations (with and without duct firing). The most representative worst-case scenario for short-term (startup mode) CO was assumed to be 60% load at a temperature of 64 degrees F from the previous modeling.

The modeled hourly emission rates from the combustion turbines used for this analysis are also provided in Table 3. The CO short-term emission rate of 3,600 lb/hour per CTG was modeled. This emission rate conservatively assumes that the entire worst case startup emissions provided as lb/event values in Table 2 will occur in the first hour of startup for the 1-hour averaging period. Similarly, the entire 8,004 lb/day emissions were assumed to occur in an 8-hour period, giving an average worst case 8-hour emission rate of 1,000 lb/hour.

Table 3
BEP Source Parameters[a] and Modeled CO Emission Rates

Source	Stack Height (m)	Stack Diameter (m)	Exit Temp. (K)	Exit Velocity (m/s)	CO Emissions (lb/hour/unit)
CTGs (1-hour)	39.62	5.64	366	13.7	3,600
CTGs (8-hour)	39.62	5.64	366	13.7	1,000
Fire Water Pump	9.14	0.13	796	59.6	2.02

a. Stack parameters reflect 60% load as representative of startup operations.

The operation of the firewater pump consists of weekly testing and maintenance. Testing will generally occur once per week during daytime hours. For emissions modeling purposes, the firewater pump was conservatively assumed to operate full time.

6.2 Results of the Air Quality Modeling Analysis

This section presents the results of the air quality impact analysis performed for the proposed BEP CO emission limits. The modeling input and output files are included on a compact disk in Appendix A.

Federal PSD regulations require that proposed major sources, such as BEP, not contribute to air pollutant concentrations in excess of the PSD increments or cause an exceedance of the AAQS. Attainment areas are divided into Class I and Class II areas for the PSD analysis. More sensitive Class I areas (e.g., formally designated wilderness areas, national parks and monuments) are protected by the most stringent PSD increments, with the remainder of the attainment areas evaluated in terms of Class II PSD increments. There are no PSD increments for CO. The BEP vicinity is classified as a Class II area.

6.2.1 Significant Impact Analysis for CO

The portion of Riverside County where the project is located is currently classified as attainment for CO. As an initial step, emissions from the BEP CTGs were modeled and resulting worst case ambient air quality impacts were compared to the Significant Impact Levels (SILs). Since the impacts were projected to be above the SILs, an CAAQS analysis was performed. The SILs and CAAQS for CO are shown in Table 4.

Table 4
CO Significant Impact Levels and Ambient Standards

Pollutant	Average Period	SIL ($\mu g/m^3$)	CAAQS ($\mu g/m^3$)
CO	1-hour	2,000	23,000
	8-hour	500	10,000

A modeling assessment was performed to determine the maximum impacts from the CO start-up operations. The worst-case hourly and eight hour emission rates of CO from the CTGs during startup were modeled as shown in Table 3. The results of this analysis are shown in Table 5 and the impacts exceed both the 1 and 8-hour SILs. Therefore, other sources in the area were modeled.

6.2.2 Comparison of Impacts to PSD Monitoring Threshold

A comparison of the facility's highest predicted carbon monoxide impacts with the EPA-specified pre-construction monitoring concentrations was made. The 8-hour impact of 517 $\mu g/m^3$ is below the pre-construction monitoring concentration of 575 μg/m^3. Therefore pre-construction monitoring is not required.

Table 5
Maximum Short-term Modeled CO Impact During Startup

Pollutant	Averaging Period	Maximum Impact [a] (μg/m^3)	Significant Impact Level (μg/m^3)
CO	1-hour	5,075	2,000
	8-hour	517	500
a. Maximum 1-hour impact overly conservative by assuming entire worst case startup (3,600 lb/event per CTG) CO emission rate occurs in one hour. Maximum 8-hour impact is also very conservative assuming entire daily limit of 8,004 lb/day per CTG occurs within eight hours.			

6.2.3 Cumulative Impact Analysis

Since the short-term impacts exceed the SILs shown in Table 5, a cumulative impact analysis comparing the impact of the project and other nearby sources to the AAQS is required. For this cumulative analysis the nearby proposed Blythe Energy II (BEP II) was included. BEP II is a proposed project that is currently going through the permitting process. This project is proposed by a different applicant (owner/operation) than BEP. However, it will utilize the same Siemens V84.3A technology in two combined cycle units. Although this project has proposed lower startup emission rates, the same 1-hour and 8-hour worst case emission rates shown in Table 3 were assumed for BEP II. Assuming that all four turbines simultaneously startup at the same time with worst case emission is very conservative.

The MDAQMD was contacted to determine other potential CO sources in the area. The only other sources identified were a Southern California Gas Company compressor station and a cotton gin operated by Modern Cotton Ginning Company. These sources do not operate continuously and the cotton gin is a seasonal source. However, they were also assumed to operate at their maximum CO emission rates during the simultaneous worst case startup at BEP and BEP II. The stack parameters and CO emission rates for these sources are provided in Table 6.

Table 6
Stack Parameters and Modeled CO Emission Rates for all Sources Analyzed

Source/ Model ID	UTM East (m)	UTM North (m)	Stack Height (m)	Stack Diameter (m)	Exit Temp. (K)	Exit Velocity (m/s)	CO Emissions (lb/hr/unit)
BEP HRSG/ 1001	714609	3721719	39.62	5.64	366	13.7	3,600 (1-hr) 1,000 (8-hr)
BEP HRSG/ 1002	714609	3721750	39.62	5.64	366	13.7	3,600 (1-hr) 1,000 (8-hr)
BEP FWP/ 1003	714574	3721735	9.14	0.13	796	59.6	2.02
BEP II HRSG/ 2001	714315	3721351	39.62	5.64	366	13.7	3,600 (1-hr) 1,000 (8-hr)
BEP II HRSG/ 2002	714284	3721351	39.62	5.64	366	13.7	3,600 (1-hr) 1,000 (8-hr)
BEP II FWP/ 2003	714299	3721316	9.14	0.13	796	59.6	2.02
So Cal Gas/ 3001	718680	3720786	9.14	0.31	866	19.5	45.9
So Cal Gas/ 3002	718680	3720786	10.97	0.64	721	36.08	11.0
So Cal Gas/ 3003	718680	3720786	5.79	0.31	747	10.18	2.3
Modern Ginning/ 4001	722900	3719000	8.54	0.97	300	3.45	2.3
Emission rates for BEP and BEP II as described in this application. Source parameters and locations for all sources except Modern Ginning Co. obtained from previous modeling files. Emission rate and UTMs for Modern Ginning Co. obtained from MDAQMD. Source parameters for Modern Ginning Co. estimated based on other cotton gins.							

The results of the cumulative modeling analysis are provided in Table 7. The background air quality data was obtained for the most recent three year period from Palm Springs. This location is expected to provide conservatively representative background data for an area in the desert along the I10 freeway. In spite of the very conservative assumptions used for this analysis, the results are shown in Table 7 are only about 29% of the 8-hour AAQS and 40% of the 1-hour AAQS.

Table 7
Maximum Cumulative Modeled CO Impact During Startup

Pollutant	Averaging Period	Maximum Cumulative Impact [a] (µg/m³)	Background [b] Concentration (µg/m³)	Total Impact (µg/m³)	AAQS (µg/m³)
CO	1-hour	6,065	3,191	9,256	23,000
	8-hour	692	1,891	2,583	10,000

a. Maximum 1-hour impact overly conservative by assuming entire worst case startup (3,600 lb/event per CTG) CO emission rate simultaneously from four CTGs occurs in one hour. Maximum 8-hour impact is also very conservative assuming entire daily limit of 8,004 lb/day per CTG occurs within eight hours. Other sources also at their maximum operating CO emission rates during these times.

b. Maximum background ambient air concentrations observed at the Palm Springs monitoring station during 2000-2002 were used.

The carbon monoxide impacts are well below the ambient air quality standards. This analysis demonstrates that the BEP project under worst-case start up operations will not adversely impact air quality or exceed the applicable standards.

7.0 COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

The initial BEP application provided a comprehensive review of the requirements applicable to the facility and a demonstration of compliance. This petition focuses on those requirements that have changed since that time.

7.1 Ambient Air Quality Standards

The EPA has established National Ambient Air Quality Standards (NAAQS) pursuant to the Clean Air Act. The NAAQS include both primary and secondary standards for several criteria pollutants. The primary standards are designed to protect human health with an adequate margin of safety. The secondary standards are designed to protect property and ecosystems from effects of air pollution.

NAAQS have been established for ozone (O_3), PM_{10}, fine particulates ($PM_{2.5}$), CO, nitrogen dioxide (NO_2), SO_2, and lead (Pb). In addition to the NAAQS, the State of California has adopted ambient air quality standards (CAAQS) for these and other pollutants and averaging periods that are equally or more stringent than the NAAQS. Impacts are compared to the CO CAAQS as they are more stringent than the CO NAAQS.

The facility is located in the Mojave Desert Air Basin in eastern Riverside County. The eastern portion of Riverside County has been designated as a State non-attainment area for PM_{10} and O_3. The area is a State unclassified area for CO, and unclassified or attainment for all federal criteria pollutants. Consistent with federal requirements, an unclassifiable designation is treated the same as an attainment designation. Therefore, both the California Air Resources Board (ARB) and EPA consider Eastern Riverside County as in attainment for CO, NO_2, SO_2, and Pb.

7.2 Summary of Applicable District Rules and Regulations

The FDOC provided a comprehensive review of the requirements applicable to the facility. This application focuses on those requirements that have changed since the FDOC was issued. The following MDAQMD Rules that potentially apply to BEP are listed below:

- Rule 221 - Federal Operating Permit Requirement
- Rule 401 - Visible Emissions
- Rule 402 – Nuisance
- Rule 403 - Fugitive Dust

- Rule 403.2 - Fugitive Dust Control for the Mojave Desert Planning Area
- Rule 404 - Particulate Matter – Concentration
- Rule 405 - Solid Particulate Matter – Weight
- Rule 406 - Specific Contaminants
- Rule 408 – Circumvention
- Rule 409 - Combustion Contaminants
- Rule 430 - Breakdown Provisions
- Rule 431 - Sulfur Content of Fuels
- Rule 475 - Electric Power Generating Equipment
- Rule 900 - Standards of Performance For New Stationary Sources (NSPS)
- Rule 1200 – Federal Operating Permits, General
- Rule 1300 – NSR, General
- Rule 1302 – NSR, Procedures
- Rule 1303 – NSR, Requirements
- Rule 1306 – NSR, Electric Energy Generating Facilities
- Rule 1320 – NSR, Toxic Air Contaminants
- Rule 1520 - Control of Toxic Air Contaminants from Existing Sources

Only those rules that have been updated or adopted since the FDOC was issued, or rules for which compliance is affected by the proposed change in startup CO emissions, are discussed in detail in the following subsections.

7.2.1 Rule 1200 – Federal Operating Permits, General

The MDAQMD has been delegated authority to administer the federal Title V program. A permit application pursuant to 40 CFR Part 70 and MDAQMD Regulation XII (Federal Operating Permits) will be submitted to MDAQMD within 12 months after commercial startup of the facility and will incorporate the CO permit limits presented in this application.

Continuous emissions monitoring systems (CEMS) for CO emissions are required by the FDOC and PSD permit. No other compliance assurance monitoring (CAM) requirements (40 CFR 64) related to this modification is expected to apply to this facility.

BEP previously submitted an application to MDAQMD pursuant to 40 CFR 72 for an acid rain permit. The modifications proposed in this application do not affect the acid rain program requirements (e.g., NO_x monitoring and SO_2 allowances) and hence the certification of compliance is still valid. The MDAQMD has issued a draft Acid Rain permit for BEP and it is expected that these requirements will be incorporated into the Title V permit discussed above.

7.2.2 Rule 1300 – NSR General Provisions

This application is being submitted to fulfill the MDAQMD requirements related to NSR. In addition, BEP has submitted a PSD application to EPA for the proposed revision to CO startup emission limits. Rule 1300 also includes a requirement for compliance with Rule 1320 (New Source Review for Toxic Air Contaminants). A Rule 1320 compliance determination is provided in this Section.

7.2.3 Rule 1302 – NSR Procedures

Rule 1302(B)(1)(a)(ii) requires that the Comprehensive Emissions Inventory (Inventory) be updated in order for this application to be deemed complete. The information provided in Section 2 provides the necessary information to update the Inventory for CO. No other changes to the Inventory are requested.

Rule 1302(D)(5)(b)(iii) requires that the applicant certify, in writing, prior to the issuance of any permit that all Facilities that are under the control of the same person (or persons under common control) in the State of California, are in compliance with all applicable emissions limitations and standards under the Federal Clean Air Act and the applicable implementation plan for the air district in which the Facility is located. FPL Energy, the parent company of Blythe Energy LLC, operates other facilities in California, including the Solar Energy Generating Stations (SEGS) near Barstow, California, and a power generating station in the Port of Stockton, California. As stated in Chapter 1, the MDAQMD issued a draft permit in August 2004. This draft permit was issued based on an application submitted in December 2003, which contained the certification required by Rule 1302(D)(5)(b)(iii).

7.2.4 Rule 1303 – NSR Requirements

Neither BACT nor offsets pursuant to Rule 1303(A) and (B) are not required by MDAQMD since Eastern Riverside County is attainment for CO. However, EPA requested that a BACT analysis for an oxidation catalyst be performed for the PSD permit modification. Therefore, this information is provided below.

BACT Technical Feasibility

In assessing whether a particular control device is technically feasible for a given application, the following factors were considered:

- Is it physically possible to install and operate the alternative?
- Will safe operation of the facility be assured using the alternative?
- Could normal or (reasonably anticipated) upset conditions associated with the alternative significantly damage or in some other way adversely affect the production system or the quality of the product?
- Has the technology been successfully demonstrated in practice for similar units, and for a similar purpose?

Based on consideration of these factors, BEP acknowledges that it would be possible to install and operate an oxidation catalyst to control startup emissions of CO from the BEP units. In that sense, such an installation would be technically feasible.

What is less clear in this case, however, is the degree to which an oxidation catalyst would be effective in reducing CO emissions generated during startup for this specific application. The limitations discussed below were taken into account in determining whether an oxidation catalyst represents BACT for BEP startup CO emissions:

1. Warm-up-phase startup emissions will not be fully controlled

An oxidation catalyst will not achieve its optimal effectiveness until the catalyst temperature reaches a sufficient temperature. According to information published by Engelhard, a leading manufacturer of catalytic control equipment, a minimum temperature of 500°F is needed to provide high levels of CO emissions control. At catalyst temperatures below 500°F, CO emissions reduction falls off rapidly. Therefore an oxidation catalyst will not control the CO emitted in the warm-up phase of the startup sequence as well as it would control CO emissions after the entire catalyst bed is at design temperature. Neither catalyst supplier startup data nor actual operating data with a CO catalyst was available. Therefore, estimates were made based on limited existing data from BEP startups and extrapolation of catalyst supplier curves. Using these projections, it is expected that from 20 to 60 minutes will be required to uniformly heat the oxidation catalyst to 500°F, depending on whether the unit is in a cold, warm, or hot startup sequence. Note that only a hot start provides any benefit over a cold start (warm starts were not appreciably different from a CO emissions perspective than cold starts). The potential for poorly or marginally controlled CO emissions are estimated as shown in Table 8.

Table 8
Estimate of Uncontrolled CO Emissions During Startup Warm-Up Phase

Type of Start	Time to Achieve 500°F (minutes)	Uncontrolled Warm-Up Phase Startup CO Emissions (lbs)
Cold	60	1,700
Warm	60	1,700
Hot	20	520

2. A catalyst bed will increase system pressure drop

A catalyst bed to control startup emissions of CO would increase backpressure to the unit at all times (not just when the CTG is in startup mode). Based on information provided to ENSR by Engelhard (for a smaller-sized catalyst designed for 80% CO conversion), it is estimated that a backpressure increase of at least two inches of water (2" WG) pressure drop may be expected for the installation of an oxidation catalyst to each of the BEP units. This added pressure would result in diminished energy efficiency for the system. Information provided to ENSR by Westinghouse indicates that for a combustion turbine similar to the BEP units, a loss of approximately 0.07% energy generation would result from a 2" WG increase in backpressure. This translates to an annual operating cost that must be included in the economic impact assessment for this option. This impact on energy efficiency will also translate to **increased emissions of all other pollutants from this and/or other plants** to serve required energy needs whenever the plant is running regardless of the power generation level.

3. The location available for retrofit to the BEP system is limited to the "cold side" of the existing HRSG

A location has been identified within the BEP system where it is physically possible to retrofit an oxidation catalyst. This location, however, is not in the place where the exhaust gases will be at their hottest during system startup; and is a location that will require extended warm-up time for the catalyst bed. As discussed above, the effectiveness of an oxidation catalyst is dependent on the entire catalyst bed being at a sufficient temperature. A comparison of the effectiveness estimated for an oxidation catalyst for the BEP retrofit application to the effectiveness an oxidation catalyst applied to some other gas turbine system should take into account whether the oxidation catalyst was included in the original design for that other system.

4. The effective life of an oxidation catalyst is limited

Catalyst suppliers typically do not guarantee effective CO control performance for more than three years (at steady state normal operating temperature). Catalyst suppliers are not willing to guarantee any performance level during transient startup conditions and/or at low temperatures. Early catalyst failure has been observed due, for example, to potential fouling agents present in turbine lubrication oil or fuel additives. Therefore, the estimation of cost includes the cost of replacing the full catalyst bed every three years. It is noted that other system components may remain in place and so the amortization of the costs associated with those elements of the control system has been applied over a 15 year period (see the discussion of economic feasibility, presented below).

5. Catalyst beds are occasionally found to be non-effective

Experience with oxidation catalysts, including those in similar applications, indicates that occasionally they can fail suddenly and irreversibly, and therefore must be replaced immediately. For this reason, it will be necessary to provide for the availability of a replacement bed that can be installed quickly. Therefore, the estimation of cost includes the cost of purchasing one additional catalyst bed (see the discussion of economic feasibility, presented below), to be maintained as an on-site spare.

BACT Economic Feasibility

The economic impact associated with the retrofit of a hypothetical oxidation catalyst to reduce startup CO emissions from the BEP system was estimated as follows:

- Economic impact was estimated for an individual CTG/HRSG.
- A 15-year amortization period and an interest rate of 6% were employed in the estimation of annualized cost.
- Estimates of the cost of the catalyst beds were obtained from Engelhard and Vogt. The lower per-unit cost, $432,000, provided by Engelhard, was used to estimate cost-effectiveness. The per-unit cost provided by Vogt was $550,000.
- A three-year catalyst bed replacement cycle was assumed, based on the information provided by the suppliers. The amortization period employed for the catalyst bed cost, therefore, was three years (amortization was at a 6% interest rate). A bed replacement labor cost of $40,000, which would be incurred once every three years, was also estimated, based on information obtained from Foster-Wheeler.

- The cost estimate includes provision for purchase of one additional bed that would be available as an on-site spare. The cost of the spare bed was amortized over a 15 year period since this would be a one-time expenditure.
- Aside from the catalyst costs, the estimate of system capital costs were based on the cost associated with modifying the existing HRSG to accommodate the retrofit of the oxidation catalyst. This includes costs of purchased equipment, installation, engineering, construction, and other indirect costs. Estimates of these direct and indirect capital costs were made based on information published by EPA, in particular using cost factors presented in the EPA Control Cost Manual, Sixth Edition.
- An energy penalty cost of approximately $39,000/year accounting for the efficiency loss due to increased system pressure drop (and an energy cost of $0.035/kWhr was included in the estimate.
- System operating and maintenance, and other annual costs, were estimated through cost factors presented in the EPA Control Cost Manual, Sixth Edition.
- Considering the economic impact relative to startup CO emissions only, the emissions reduction achievable through the retrofit of the oxidation catalyst was estimated based on the estimated uncontrolled average of 2,200 lb/event (see Chapter 2) and as many as 300 events per year. This translates to up to 330 tpy of uncontrolled startup CO emissions. The estimate of controlled emissions was derived by assuming that emissions during the first hour would be 1,700 pounds uncontrolled. Since the oxidation catalyst would not yet have achieved the 500°F temperature necessary for full reduction of CO emissions, the overall reduction of CO emissions provided by the catalyst during that warm-up phase would be about 25%. Then, for the remaining portion of the startup sequence, it was assumed that the emissions reduction provided by the oxidation catalyst would be 90%. This yields an estimate of total as-controlled emissions equal to 1,260 lb/event, or 189 tpy for 300 startup events per year. This in turn provides an estimate of up to 141 tpy of CO emissions reduction, assuming the maximum possible number of annual startup events. In actual operations, the number of startups and associated emissions of CO are expected to be much lower.
- Relative to annual CO PTE, which includes both startups and normal operations, the emissions reduction achievable through the retrofit of an oxidation catalyst was estimated to be 165.5 tpy. This reduction is based on reducing startup CO emissions by 141 tpy and reducing the remaining CO emissions (i.e., from shutdowns and from normal operations) by 90%.

The various cost factors discussed above are summarized in Appendix B. Based on the above, the overall economic impact associated with the installation of an oxidation catalyst for hypothetical control of startup CO emissions from the BEP system was estimated to be at least $2,440/ton of emissions reduction relative to startup CO emissions only. If the operations emissions are included in the potential reductions, the overall economic impact associated with the retrofit of an oxidation catalyst for annual CO was estimated to be at least $2,080/ton of emissions reduction. These costs could be much higher if based on actual emissions and/or fewer startups rather than the very conservative assumptions employed in this application.

Based on limitations to its potential effectiveness for this specific facility due to temperature dependency during startups, high costs relative to the low expected impact of the CO emissions (see Chapter 6), the low HAP emissions, and the very conservative assumptions upon which these analyses are based, an oxidation catalyst to control emissions of CO during startups represents a considerable cost and does not represent "BACT" for the Blythe Energy Project.

7.2.5 Rule 1306 – NSR for Electric Energy Generating Facilities

Rule 1306 places additional administrative requirements on projects involving approval by the CEC. This petition satisfies the requirements of Rule 1306.

7.2.6 Rule 1320 – NSR for Toxic Air Contaminants

The proposed modification in startup emissions presented in this application will not have a significant impact on the toxic emissions. Previous toxic emissions calculated for the facility demonstrates the BEP facility is not a major source of HAPs.

A review of National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations from 40 CFR 61 and 40 CFR 63 was conducted. The Stationary Combustion Turbine NESHAP (40 CFR 63 Subpart YYYY) was finalized in August 2003 and published in the Federal Register on March 5, 2004.

The Stationary Combustion Turbine NESHAP applies to any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP. The BEP facility is not a major source of HAP so this standard does not apply.

7.2.7 Rule 1520 – Control of Toxic Air Contaminants from Existing Sources

As stated above, the proposed modification to startup emissions will not have a significant impact on toxic emissions. The previous health risk assessment prepared for the facility showed that the predicted health risks due to facility operations are below the public notification and risk reduction requirements of Rule 1520, therefore there are no additional requirements under this rule for the proposed revised startup emissions.

8.0 POTENTIAL EFFECTS ON PROPERTY OWNERS AND THE PUBLIC

The proposed modifications to the CEC Conditions in the Air Quality category will not affect project equipment or the significance of environmental impacts. Therefore, the proposed modifications are not anticipated to affect nearby property owners, the public, or parties in the application proceedings. The nearest residence to the facility is less than one mile away.

The list of property owners potentially affected by the modification is provided in Table 9 below.

Table 9
List of Property Owners

APN	Owner	Address
824-110-039	HENRY S. WHITE	361 N PALM DR; BLYTHE CA 92225-1525
824-110-037	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-110-036	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-110-035	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-110-038	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-110-004	SCHINDLER BROS INC	14020 W HOBSONWAY; BLYTHE CA 92225-2370
824-110-020	LAURIE SHANKS	46251 WHITE OAK CT; KING CITY CA 93930-9769
824-110-021	LAURIE SHANKS	46251 WHITE OAK CT; KING CITY CA 93930-9769
824-110-018	HARLAN H & PATRICIA A CHOAT	PO BOX 946; BLYTHE CA 92226-0946
824-110-011	SCHINDLER BROS INC	14020 W HOBSONWAY; BLYTHE CA 92225-2370
824-110-016	HARLAN H & PATRICIA A CHOAT	PO BOX 946; BLYTHE CA 92226-0946
824-110-019	CARLILE R GREY	1835 S GATEWAY BLVD; RIDGECREST CA 93555-8112
824-110-026	HENRY A & LOUIS SCHINDLER	14020 W HOBSONWAY; BLYTHE CA 92225-2370
824-110-012	LOUIS R & DOROTHY HOOVER	12470 W HOBSONWAY; BLYTHE CA 92225-2386
824-110-003	SCHINDLER BROS IN	14020 W HOBSONWAY; BLYTHE CA 92225-2370
824-110-009	JOSE A & KENNI MEDINA	7 RIO LOCO; BLYTHE CA 92225-9539
824-110-010	VANDERPLOEG TRUST	12507 NEIGHBOURS BLVD; BLYTHE CA 92225-9788
824-110-040	RUSSELL & ROMA DUQUETTE	14391 W RIVERSIDE DR; BLYTHE CA92225-9774
824-110-029	JOE & PRISCILLA VANDYKE	14271 W RIVERSIDE DR; BLYTHE CA 92225-9778
824-110-032	ROBERT R MACDONALD	14295 W RIVERSIDE DR; BLYTHE CA 92225-9778
824-110-028	TROY VANDERPLOEG	14625 W RIVERSIDE DR; BLYTHE CA 92225-9776
824-110-031	DOYLE R THOMPSON	931 N EUCALYPTUS AVE; BLYTHE CA 92225-1004
824-110-022	JOHN J & LETTY M STILES	12491 TOBY LN, BLYTHE CA 92225-9784
824-110-023	JOHN J & LETTY M STILES	12491 TOBY LN, BLYTHE CA 92225-9784
824-121-001	VIRGILL & DOROTHY K JONES	7435 7TH AVE; BLYTHE CA 92225-9235
824-122-016	PVID	PO BOX 1199; BLYTHE CA92226-1199
824-122-013	SUN WORLD INTERNATIONALINC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-122-014	ELEANOR E & ROBERT T ALVARADO	14499 W HOBSONWAY; BLYTHE CA 92225-2357 CO03
824-122-015	CROWN ENTS INC	12226 STEPHENS RD; WARREN MI 48089-2015

Table 9
List of Property Owners

APN	Owner	Address
824-122-011	VIRGIL I & DOROTHY K JONES	7435 7TH AVE; BLYTHE CA 92225-9235
824-122-009	VIRGIL I & DOROTHY K JONES	7435 7TH AVE; BLYTHE CA 92225-9235
824-130-007	IQBAL AHMED	4507 WHEELER AVE; LAVERNE CA 91750
824-080-005	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-080-004	COUNTY OF RIVERSIDE	3525 14TH ST; RIVERSIDE CA 92501-3813
824-080-003	SUN WORLD INTERNATIONAL INC	15550 W HOBSONWAY , BLYTHE CA 92225-3317
824-090-035	JEAN U SMITHERS	16531 W HOBSONWAY; BLYTHE CA 92225-3324
824-090-028	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-090-032	RONALD E & RITA D DAWSON	16275 W HOBSONWAY; BLYTHE CA 92225-2375
824-090-036	RONALD E & RITA D DAWSON	16275 W HOBSONWAY; BLYTHE CA 92225-2375
824-090-031	RONALD E & RITA D DAWSON	16275 W HOBSONWAY; BLYTHE CA 92225-2375
824-090-037	RONALD E & RITA D DAWSON D	16275 W HOBSONWAY; BLYTHE CA 92225-2375
824-090-026	RONALD E & RITA D DAWSON D	16275 W HOBSONWAY; BLYTHE CA 92225-2375
824-090-033	WALTER LUCAS	4840 RHEDA WI EDEN BRUECK; WEST GERMANY
824-090-009	IQBAL AHMED	4507 WHEELER AVE; LAVERNE CA 91750
824-090-020	BEN F & ANN A GOSSER	2137 W 183RD ST; TORRANCE CA 90504-5402
824-090-044	BEN F & ANN A GOSSER	2137 W 183RD ST; TORRANCE CA 90504-5402
824-090-042	BEN F & ANN A GOSSER	2137 W 183RD ST; TORRANCE CA 90504-5402
824-090-018	RONALD E & RITA D DAWSON	16275 W HOBSONWAY; BLYTHE CA 92225-2375
824-090-034	JEAN U SMITHERS	16531 W HOBSONWAY; BLYTHE CA92225-3324
824-090-025	THOMAS E & SANDRA L NORDELL	16531 W HOBSONWAY , BLYTHE CA 92225-3324
824-090-024	DESERT CITRUS PROP INC	16401 KIN BLVD, BLYTHE CA92225
824-101-014	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-101-020	UNITED STATES FEDERAL GOV'T	PO BOX 281213; LAKEWOOD CO 80228-8213
824-101-008	UNITED STATES FEDERAL GOV'T	US DEPT OF INTERIOR; WASHINGTON DC 21401
824-101-009	UNITED STATES FEDERAL GOV'T	US DEPT OF INTERIOR; WASHINGTON DC 21401
824-101-012	RIVERSIDE COUNTY POWER C/O REED SMITH	1650 MARKET ST; PHILADELPHIA PA 19103-4201
824-101-013	RIVERSIDE COUNTY POWER C/O REED SMITH	1650 MARKET ST; PHILADELPHIA PA 19103-4201
824-101-017	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-101-016	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-101-015	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-101-007	COUNTY OF RIVERSIDE	3133 7TH ST; RIVERSIDE CA 92501
824-101-019	BLYTHE ENERGY	700 UNIVERSE BLVD; JUNO BEACH FL 33408-2657
824-102-024	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-102-023	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-102-025	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-102-020	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-102-027	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
824-102-014	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002

Table 9
List of Property Owners

APN	Owner	Address
824-102-013	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
824-102-016	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
824-102-015	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
824-102-026	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
863-050-007	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
863-050-004	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
863-060-016	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
863-060-018	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
863-060-017	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
863-060-015	DESERT CITRUS PROP INC C/O VENTURA COASTAL CORP	2325 VISTA DEL MAR; VENTURA CA 93002
863-060-004	DAVID F & ERNESTO ALVAREZ	78365 HIGHWAY 111; LA QUINTA CA 92253
863-070-016	MICHELLE OWEN WALKER	PO BOX 1473; BLYTHE CA 92226-1473
821-110-003	COUNTY OF RIVERSIDE	352514TH ST; RIVERSIDE CA 92501-3813
821-110-004	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-028	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-027	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-025	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-026	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-035	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-034	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-046	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-047	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-030	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-029	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-038	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-040	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-048	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-044	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-042	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-043	SUN WORLD INTERNATIONAL INC	PO BOX 80298; BAKERSFIELD CA 93380-0298
821-120-024	UNITED STATES FEDERAL GOV'T 821	US DEPT OF THE INTERIOR; WASHINGTON DC 21401
821-120-015	JOHN D & NANCY C VANDERSLICE	PO BOX 5354; MOHAVE VALLEY AZ 86446-5354

Table 9
List of Property Owners

APN	Owner	Address
821-120-017	ROBINSON FARMS	PO BOX 2399; BLYTHE CA 92226-2399
821-120-019	LOS CERRITOS CAPITAL CORP	88100 58TH AVE; THERMAL CA 92274-9470
821-120-039	SUN WORLD INTERNATIONAL INC	10950 BUCK BLVD, BLYTHE CA 92225
821-120-023	RICHARD W & ANGELINA A DILL	15000 RIVERSIDE DR, BLYTHE CA 92225

9.0 SUMMARY OF REQUEST

As demonstrated in this petition, the requested modifications of the air quality Conditions of Certification are not anticipated to have an adverse effect on the public or the environment. The modifications will not affect compliance with applicable LORS. Accordingly, BEP requests that the Energy Commission Staff expedite review of this petition, and request Commission approval of the proposed modified conditions in accordance with Title 20 CCR Section 1769 (a)(3).

10.0 REFERENCES

U.S. Environmental Protection Agency, 1998. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I, Section 1.4 "Natural Gas Combustion."

U.S. Environmental Protection Agency, 2000. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I, Section 3.1 "Stationary Gas Turbines."

U.S. Environmental Protection Agency, 2003. Guideline on Air Quality Models. 40 CFR Part 51, Appendix W. April 2003. (Available at http://www.epa/gov/scram001)

APPENDIX A

MODELING FILES
(provided on compact disk)

APPENDIX B

OXIDATION CATALYST COST-EFFECTIVENESS ESTIMATE

Appendix B
Blythe Energy, LLC
Oxidation Catalyst Cost-Effectiveness Estimate

EMISSIONS REDUCTION EFFECTIVENESS

• Uncontrolled emissions		330 TPY	Based on 300 startup events @ 2,200 lb/event
• Controlled emissions		189 TPY	Based on 300 startup events @ 1,260 lb/event = 75% of 1,600 lb/event + 10% of 600 lb/event
• Emissions reduction	**ER**	**141 TPY**	330.00 TPY - 189.00 TPY

COST ESTIMATION PARAMETERS

• Interest rate on capital expenditure	i	6 %	Typical value (calendar year 2003)
• Economic life of equipment	n	15 yrs	Typical value
• Capital recovery factor	**CRF**	**0.103**	CRF = (i/100) * { [1 + (i/100)]^n } / { [1 + (i/100)]^n - 1 }

CAPITAL COST

• **DIRECT CAPITAL COST**			
■ Purchased Equipment Cost:			
♦ HRSG modifications and catalyst Housing	A	$187,500	Based on USEPA Combustion Turbine Workgroup Memorandum, 09/04/1998
♦ Instrumentation and controls	0.10A	$18,750.00	OAQPS Control Cost Manual, Table 3.8
♦ Taxes and freight	0.10A	$18,750.00	OAQPS Control Cost Manual, Table 3.8
♦ Total purchased equipment cost	B	$225,000.00	B = 1.2 * A
■ Installation cost	0.30B	$67,500.00	OAQPS Control Cost Manual, Table 3.8
■ Site preparation and buildings cost	C_{sp}	$0	Based on retrofit to existing system
■ **Total Direct Capital Cost**	**DCC**	**$292,500.00**	DCC = 1.30B + C_{sp}
• **INDIRECT CAPITAL COST**			
■ Engineering	0.10B	$22,500.00	OAQPS Control Cost Manual, Table 3.8
■ Construction and field expenses	0.05B	$11,250.00	OAQPS Control Cost Manual, Table 3.8
■ Contractor fees	0.05B	$11,250.00	OAQPS Control Cost Manual, Table 3.8
■ Startup and performance tests	0.03B	$6,750.00	OAQPS Control Cost Manual, Table 3.8
■ Contingencies	0.03B	$6,750.00	OAQPS Control Cost Manual, Table 3.8
■ Working capital	WC	$2,953.13	OAQPS Control Cost Manual, Table 3.8
■ **Total Indirect Capital Cost**	**ICC**	**$61,453.13**	ICC = 0.26B + WC
• **TOTAL CAPITAL COST**	**TCC**	**$353,953.13**	TCC = DCC + ICC

Appendix B
Blythe Energy, LLC
Oxidation Catalyst Cost-Effectiveness Estimate (Continued)

ANNUALIZED COST

- **CATALYST COSTS**

■ In-Use Bed Purchase Cost:

♦ Catalyst unit cost	U_c	$432,000 /bed	Based on data provided by Engelhard
♦ Sales tax and freight	$0.10U_c$	$43,200.00 /bed	OAQPS Control Cost Manual, Table 3.8
♦ Total catalyst purchase cost	$C_{cp,\,iu}$	$475,200.00 /bed	$432,000 + $43,200
♦ Interest rate on capital expenditure	i	6 %	Typical value (calendar year 2003)
♦ Catalyst life		3 yr/bed	Based on Engelhard data for a similar installation
♦ Catalyst capital recovery factor	CRF_{cr}	0.314	$CRF = (i/100) * \{ [1 + (i/100)]^n \} / \{ [1 + (i/100)]^n - 1 \}$
♦ Annualized initial purchase cost	$A_{cp,\,iu}$	$149,264.98 /yr	$475,200 * 0.314

■ Backup Bed Purchase Cost:

♦ Number of beds		1	To be available for immediate replacement of in-use bed
♦ Catalyst unit cost	U_c	$432,000	1 bed * $432,000/bed
♦ Sales tax and freight	$0.10U_c$	$43,200.00	OAQPS Control Cost Manual, Table 3.8
♦ Total catalyst purchase cost	$C_{cp,\,b}$	$475,200.00	$432,000 + $43,200
♦ Economic life of equipment		15 yr	Based on Engelhard data for a similar installation
♦ Catalyst capital recovery factor	CRF_{cr}	0.103	See above, for 15-year economic life
♦ Annualized initial purchase cost	$A_{cp,\,b}$	$48,927.91 /yr	$475,200 * 0.103

■ Catalyst Replacement Cost:

♦ Catalyst replacement labor		$40,000 /bed	Based on estimate provided by Foster Wheeler
■ **Total Catalyst Cost:**	C_c	**$211,526.22 /yr**	$149,265/yr + $48,928/yr + ($40,000/bed * 1 bed / 3 years)

Appendix B
Blythe Energy, LLC
Oxidation Catalyst Cost-Effectiveness Estimate (Concluded)

ANNUALIZED COST

● **DIRECT OPERATIONAL COSTS**			
■ Electricity Cost:			
♦ Pressure drop		2 "WG	Based on data provided by Engelhard for a similar installation
♦ Power loss due to pressure drop		1,103,760 kWhr/yr	Based on information provided by Westinghouse
♦ Electricity unit cost		$0.035 /kWhr	Typical value
♦ Total electricity cost	C_e	$38,631.60 /yr	1,103,760 kWhr/yr * $0.035/kWhr
■ Labor Costs			
♦ Operator	C_{lo}	$20,531.25 /yr	Estimate: $37.5/hr * 547.5 hr/yr
♦ Supervisor	C_{ls}	$3,079.69 /yr	Estimate: 15% of operator labor
♦ Maintenance	C_{lm}	$6,159.38 /yr	Estimate: 30% of operator labor
♦ Total Labor Cost	C_l	$29,770.31 /yr	$C_l = C_{lo} + C_{ls} + C_{lm}$
■ Maintenance Materials	C_m	$6,159.38 /yr	Estimate: 100% of maintenance labor cost
■ **Total Direct Operational Cost**	**DOC**	**$74,561.29 /yr**	$DOC = C_e + C_l + C_m$
● **INDIRECT OPERATIONAL COSTS**			
■ Overhead	O	$11,127.94 /yr	44% of direct labor cost + 12% of maintenance labor cost
■ Administration	A	$7,079.06 /yr	2% of TCC
■ Insurance	I	$3,539.53 /yr	1% of TCC
■ **Total Direct Operational Cost**	**IOC**	**$21,746.53 /yr**	IOC = O + A + I
● **TOTAL OPERATIONAL COST**	**TOC**	**$307,834.04 /yr**	$TOC = C_c + DOC + IOC$
● **ANNUALIZED CAPITAL COST**	**ACC**	**$36,443.99 /yr**	ACC = TCC * CRF
● **TOTAL ANNUALIZED COST**	**TAC**	**$344,278.03 /yr**	TAC = ACC + TOC
COST-EFFECTIVENESS	**C-E**	**$2,441.69 /ton reduction**	C-E = TAC / ER

Note: Overall CO costs were assumed by calculating uncontrolled emissions as 300 starts/year at 2,200 lb/event, plus 4,944 hours/year of typical normal operations at 8 lb/hr, plus 48 lb/event for 300 shutdowns/year = 357 tpy. Controlled emissions were based on 300 starts/year at 1,260 lb/event (25% control for the first hour, 90% after) and 90% control on normal operations and shutdown, for a total emissions of 192 tpy. Total CO emissions reduction would be 357 tpy - 192 tpy = 165 tpy. The overall cost effectiveness was estimated based on the same costs as shown above for startup emissions only with this slightly greater total CO emissions.